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ESP screening tool

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PROJECT DESCRIPTION SHEET

Name of the candidate: Robin Bredsten

Thesis title (Norwegian):   ESP søkeverktøy

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Background

Electrically Submersible Pumps (ESPs) is a relatively new technology gaining increased interests. Downhole boosting may have a huge impact on the recovery from a well. One challenge is to select which wells are best suited for ESP. This depends on several parameters that can be found in daily drilling reports (DDR/DBR) and from production profiles. Statoil alone has about 500 subsea wells and 800 platform wells. The task is to develop a tool, e.g. in excel where these parameters can be input. The tool shall then advice if the well is a good ESP candidate, preferably by estimating the added NPV of installing an ESP in this well.

Work description

1. Literature study: Describe ESPs and published experiences.
2. Discuss relevant properties of both the ESP and the well that can be used to decide if an ESP shall be installed.
3. Screening tool: design and implement a tool computing both added costs (pump, installation, rig time, etc) and increased production due to artificial lift. Discuss possibilities of making a search tool that automatically retrieves the required information.
4. Case studies: study in detail 10 or more wells and advice whether they are good ESP candidates
5. Discussion: What kind of information could have been added to improve the screening tool? How can we handle uncertainties/risk?

Abstract

Installing an electrical submersible pump can be a way to increase the production in a well. This report will explain some ways the electrical submersible pump can be installed and describe the different components in an electrical submersible pump. The report will also give an insight in how electrical submersible pumps have been used and improvements done to the electrical submersible pump on two different fields. The main part will describe a method to screen wells and find out if installing an electrical submersible pump will be profitable. The method is to estimate future oil production, based on real-time production, with and without an ESP installed, and calculate the net present value. The method takes into account costs of installing, running and removing an electrical submersible pump. The ESP screening tool is screening the wells automatically. In addition it does an ESP simulation to find applicable pumps. For the ten wells screened by the ESP screening tool, the net present values have been negative, due to weak water cut estimation.

Sammendrag

Installering av en elektrisk nedsenkbar pumpe kan være en måte til å øke produksjonen i en brønn. Denne masteroppgaven vil forklare hvordan elektriske nedsenkbare pumper kan installeres og beskrive de forskjellige komponentene. Denne masteroppgaven vil også gi en innsikt til hvordan elektriske nedsenkbare pumper kan bli installert og hvilke forbedringer som har blitt gjort på to forskjellige felt. Hoveddelen av denne oppgaven vil beskrive en metode for å screene brønner og finne ut om installasjon av en elektrisk nedsenkbare pumpe vil bli lønnsomt. Metoden går ut på å estimere fremtidig oljeproduksjon som er basert på sanntids produksjon, med og uten en elektrisk nedsenkbar pumpe installert, for så å kalkulere nåverdien. Metoden tar hensyn til installerings-, drifts- og fjerningskostnaden for elektriske nedsenkbare pumper. ESP screening verktøyet screener brønnene automatisk. I tillegg gjør den også en ESP simulering for å finne aktuelle pumper som kan brukes. For de ti brønnene som har blitt screenet av ESP screening verktøyet har alle nåverdiene blitt negative, på grunn av en svak vannkuttsestimering.

Acknowledgement

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1 Introduction

ESP is considered the most versatile of the artificial lift methods in use today. It can therefore be useful for oil companies that are producing fluids from many wells to have a tool that can screen the wells to find wells that can benefit from artificial lift. This thesis will describe one way to evaluate wells and give an indication if an electrical submersible pump should be installed. The first part of the thesis will be a study on ESP and ESP published experiences. The next part is a description of the ESP screening tool. In this section the ESP screening tool method will be explained. In order to find out if the well is a good ESP candidate, the net present value, NPV, will be calculated. The net present value must be much bigger than zero to be a good ESP candidate. The NPV calculation is based on increased production due to the ESP, installation cost, running costs and pump removal cost of the ESP, in order to include all aspects of producing with and without an ESP. The latter part of this thesis will discuss the assumptions made in the ESP screening tool and discuss future work.

2 Artificial lift and ESPs and published experiences

2.1 Artificial lift Methods

Artificial lift is different methods used to increase production from a reservoir. There are four major methods of artificial lift; Beam Pumping, Gas Lift, Hydraulic Pumping and Electrical Submersible pump. All of these methods, except ESP, will be described shortly in this chapter. ESP will be discussed extensively in the next chapter.

2.1.1 Beam Pumping

Beam pumps consist of a sucker rod string and a sucker rod pump. This technique use equipment on and below surface to increase pressure and push the oil to surface. The system works like a piston pump. On surface the beam pumping system, more commonly known as Jack pumps (Figure 1: Beam Pumping, rocks back and forth. This is connected to sucker rods, which goes down the wellbore. The sucker rods are also connected to

Figure 1: Beam Pumping

the sucker rod pumps, which is installed in the tubing, close to the bottom of the well. When the system rocks back and forth, the sucker rod pumps lift the oil from the reservoir, through the well and to surface (Rigzone.com). About two thirds of producing oil wells around the world use this kind of lift. This system is not generally applicable to be used offshore. When the wells get deeper and more deviated, problems with this system can occur (Breit & Neil Ferrier, 2008)

2.1.2 Gas Lift

The gas lift method (Figure 2: Gas Lift) injects gas back into the well to re-establish pressure, and making the reservoir produce. This can also be used to increase production in flowing wells. The injected gas reduces the bottom-hole pressure by decreasing the fluid viscosity in the well. This makes the fluid flow more easily to surface. The gas is compressed before injected down the casing tubing annulus. The gas then enters the well through many gas-lift valves. When the gas enters the well the gas forms bubbles, which help lift the fluid through reduced density and lower pressure (Rigzone.com). The gas that is being injected into the well is usually produced gas from the well or other surrounding wells.
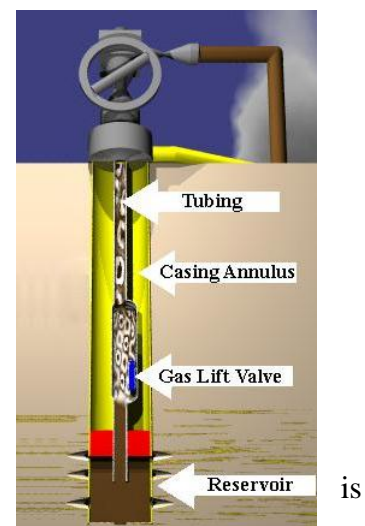

Figure 2: Gas Lift

2.1.3 Hydraulic Submersible Pump

The hydraulic submersible pump, HSP, applies a hydraulic pump downhole, which lifts the oil to surface. Using the HSP, the production fluid is forced against the pistons in the pump, creating pressure and lifts the fluids to surface. The pumps are usually installed with two pistons and a rod that goes up and down between the pistons. The surface and subsurface pumps are powered with power oil, or oil that has been produced from the well. The power oil is sent down the tubing string, with help from the surface pump, to the subsurface pump, which is installed at the bottom of the tubing string. While this process is going on, the reservoir fluids are sent to surface, up a second tubing string (Rigzone.com).

2.2 Electrical Submersible Pump
This chapter includes a complete description of ESP.

ESP is considered the most versatile of the artificial lift methods, and out of all the wells that are in need of artificial lift worldwide, around 15-20 percent employs electrical submersible pumps (Breit & Neil Ferrier, 2008). ESPs are capable of producing from 100 B/D to 90.000 B/D, giving ESP the broadest producing range of all forms of artificial lift. By installing a VSD, Variable Speed-Drive, on the ESP system, these production ranges can be higher or lower. The standard setup for an ESP is as follows. On the surface we have a switchboard connected to a junction box which again is connected to a wellhead. From the wellhead we have the tubing string that goes down to the ESP, which is normally installed above the reservoir perforations. The ESP consists of four parts, and from the top there is the pump, the gas separator or intake, the protector and at the bottom is the motor.

2.2.1 ESP installation

The most common ESP installation is to attach the ESP to the end of the tubing string and run it down the well, to the determined location. In order to retrieve the ESP, pulling of the tubing is necessary. But there are other ways to install an ESP as well. In the next chapter through-tubing conveyed ESP installation will be mentioned. This method runs the ESP through the tubing, connected to coiled tubing or a wireline. By using this method there is no need to run the tubing to remove, repair or replace the ESP. A reason to choose this method instead of the common ESP installation is that the through tubing method does not require the same workover capacity.

Another way to install ESPs was invented by Arutunoff in the early 1970s. His solution was to run the ESP using its own electric cables. The cable had to be reinforced in order to withstand the stresses caused by the weight of the ESP. The ESP was landed inside the tubing at a pump shoe that would carry the weight of the ESP and also provide a seal between the suction and the discharge sides of the pump (Takacs, 2009). When installing an ESP on a well that was not planned for ESP, retrofitting of ESP, the best alternative would be to use a through-tubing installation method. Using this method it is possible to install the ESP, without replacing the tubing as a tubing-deployed installation would require (Vinge, 2012).

2.2.2 System components

A general ESP consists of a pump, a motor, a protector, a gas separator, a power cable, a wellhead, a junction box and a switchboard. One optional add-on to the ESP will also be mentioned, the variable speed-drive, VSD.

2.2.2.1 ESP Pump

The pump used in an ESP is normally a multistage centrifugal pump. Each stage in the pump consists of one impeller and one diffuser, and the number of stages can exceed 200 (Vinge, 2012). The impellers are connected to the shaft, and runs at the same rpm as the motor. When the shaft and the impellers are spinning, centrifugal forces push the fluid from the middle of the impeller, the eye, and outwards to the edges. Unlike the impeller, the diffusers are stationary. When the pump is being assembled, impellers and diffusers are laid down in layers on the shaft and

Figure 3: Radial impeller with pressure contours

then put into a steel housing. Next they screw on a threaded base and head into the housing. The threaded head and base compresses against the outside edge of the diffusers, keeping them stationary. If the compression seizes, the diffusers would be free to rotate, and this rotation would cause the pump to lose almost all its lifting capability.
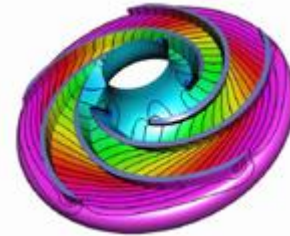
There are two kinds of impellers, radial and mixed flow. Figure 3: Radial impeller with pressure contours shows how the pressure is distributed on a radial impeller. The fluid enters the impeller at the eye. The vanes on the impeller create channels where the fluid is directed. The fluid is accelerated from the center and towards the edge of the impeller, creating a low pressure zone in the middle of the impeller. This can be explained by Bernoulli's principle. When the velocity increases, the pressure is reduced. The diffusers task is to direct the fluid from one impeller to the next one, and also convert a part of the kinetic energy, velocity energy, into potential energy, pressure (Lyons & Plisga, 2005).

2.2.2.2 ESP Motor

The submersible motor is called a prime mover. The motor is a two-pole, three-phase, squirrel-cage induction type, and it runs at a normal speed of 3500 rpm at 60 Hz operation. The motor is filled with a highly refined mineral oil that has a specific gravity between 0.8 and 0.83. This feature makes sure that the motor has the required dielectric strength to prevent short circuits between motor parts, it gives proper lubrication for the bearing and it gives the good thermal conductivity required to carry the heat generated in the motor to the outside of the housing (Takacs, 2009). The thrust bearing is a fixed-pad type, and its function is to support the thrust load of the motor rotors. The motor is cooled down by the well fluids when the fluids flow past the motor housing. Because of the required cooling effects needed in the motor, the ESP should not be placed at or below the well perforations. To provide enough cooling to the motor, a minimum fluid velocity of 1 ft/sec is recommended. The electricity needed to run the motor is led from surface via the power cable and to the motor. Because of the limited between the ESP and the inner casing diameter, a flat cable is used along the ESP.

The motor is manufactured in four different diameters; 3.75, 4.56, 5.40 and 7.38 inches. The smallest diameter, 3.75 inches, makes it possibly to use ESP in casing sizes as small as 4.5 inches. The horsepower generated from these 60 Hz motors range from 7.5 HP for the 3.75 inch to 1200 HP for the 7.38 inch motor (Lyons & Plisga, 2005). The electrical submersible pump motor differs greatly from other electric motors, due to their different working areas. These features are shown below.

1. Since the motor is run inside the well's casing string, the motors length to diameter ratio is much greater than surface motors.
2. The only way to increase the motor power of an ESP is to increase the length of the ESP.
3. The surface motors are usually cooled by air, while the ESP is cooled by the surrounding fluids in the well.
4. ESP motors have low inertia and can accelerate to full speed in less than 0.2 seconds.

When selecting the motor to be used in an ESP setup, the first demand is that the ESP must have enough power, HP. Another limitation is the inner casing diameter of the well which determines how big the ESP and the motor can be.

When starting up an ESP motor for the first time, special considerations needs to be given to the operation. When the ESP is started there is an enormous instantaneous power requirement, because of the still-standing well fluid that is occupying the tubing string. As mentioned above the motor starts in a matter of seconds and because of the high power needed, the motor draws current several times higher than its rated current. As a result of the high current at startup, there will also be a big increase in the voltage drop across the electric cable, which means that the voltage that reaches the motor terminal is reduced. In order to ensure that the ESP can be started the general rule is that 50 percent of the voltage must be available at the motor terminals, which should be checked during startup (Takacs, 2009).

2.2.2.3 ESP Protector

The main task of the protector or seal section is to isolate the motor oil from the well fluid, while the bottom-hole pressure, BHP, and the motor's internal pressure is balanced. In addition to the main task the protector has three other functions. The first is that the protector connects the pump to the motor by connecting both the housing and the drive shaft. The second is that it houses a thrust bearing to absorb pump shaft axial thrust, and the last function is that the protector allows for motor oil thermal expansion, which is resulting from operating heat rise and thermal contraction of the motor oil after shutdown (Lyons & Plisga, 2005).

The three main components of a protector are the thrust bearing, the isolation chamber and the shaft seals. The thrust bearing in the pump absorbs some the forces from the high axial forces that are developed by the impellers in the pump. The thrust bearing the protector is responsible for eliminating the bulk of these forces. The thrust bearings that are most used is the pad-type plane thrust bearing, because they have advantages over bearings with rolling elements used in other applications.

- Less heat generation in the bearing during normal operation

- Plane bearings can operate with lubricating oils containing solid particles
- Plane bearings can support high thrust loads than bearings with rolling elements

There are two types of isolation chambers in use in the industry today, and the main differences between the labyrinth- and the bag-type chambers is how they isolated the well fluids and the motor oil from each other. In the labyrinth-type chamber there is a direct contact between the motor oil and the well fluids. The name labyrinth comes from the labyrinth path the motor oil takes due to contraction and expansion of the motor oil. The proper operation of such a chamber depends on the labyrinth path the motor oil takes and the difference in specific gravity between the motor oil and the well fluids. The bag-type chamber design consists of an elastic, fluid-barrier bag to allow for thermal expansion of the motor fluid in operation, while isolating the well fluid from the motor oil. When the difference in the gravities of the motor oil and the well fluid is very small, the bag-type chamber can be used (Takacs, 2009).

A shaft seal is a rotating mechanical seal that is installed on each isolation chamber of the protector. These seals prevent communication between the motor oil and the well fluids across the protector shaft. The seal contains a stationary seal ring fixed to the protectors housing and a rotating ring turning with the shafts movement. It is these parts that provide the dynamic seal and prevents migration along the rotating shaft (Takacs, 2009).

2.2.2.4 ESP Gas separator

When free gas enters the pump section, the pumps performance is reduced. This is caused by the big difference in the specific gravities of liquids and gases. The existence of free gas at pump suction conditions, pressure and temperature affects the ESP pump in several ways.

- The head developed by the pump decreases
- When producing gassy fluids, cavitation can occur at higher flow rates causing mechanical damage of the pump stages
- When producing with very high gas rates, gas locking may occur when no pumping is taking place.

The simplest and least efficient gas separator in use often called a reverse flow gas separator. It uses the principle of gravitation separation by forcing the fluid flow to change direction and allowing free gas to escape in the wells annulus. This separator can separate low to moderate amounts of gas with a limited effect. Another separator that is often used is the rotary gas separator. This separator works on the principle that if a multiphase mixture, if spun at a high speed in a vessel, is separated to its constituent liquid and gas phases due to the different levels of centrifugal force acting on the liquid and gas phases. The rotational speed is provided by the separators shaft and separation takes place within the separator (Takacs, 2009). The most efficient gas separators can handle up to 15 percent gas in the mixture (Vinge, 2012).

2.2.2.5   ESP Cable

The electric power needed in the ESP motor is transmitted from the surface through a three-phase electric power cable. Since the ESP cables work under extremely harsh conditions there are some important requirements they must meet:

- The must have small enough diameter to fit in the annulus along the well tubing
- They must maintain their dielectric properties under harsh well conditions
    - High temperatures
    - Aggressive fluid environment
    - The presence of hydrocarbons and/or other gases
- They must be well protected against mechanical damage during running and pulling of the cable as well as normal operations

The ESP cable is a very complex unit, with many features. The three metal conductors, usually copper, is carrying the AC, Alternating Current, while the individual insulation of each conductor prevents short circuits and leakage between the conductors. The jacked provides the structural strength and the mechanical protection of the cable. Choosing and designing the right cable can ensure the cable stays operational for many years.

2.2.2.6   Surface equipment

The wellheads job is to maintain tubular control, as well as providing a positive seal around the cable and the tubing. There exist many different wellheads, with different features. The Hercules wellhead feeds the downhole power cable directly through the wellhead. In other wellheads, the power cable is cut and its end is equipped with a power connector (Takacs, 2009).

The junction box is installed between the wellhead and the switchboard. Its main purpose is to connect the power cable from the well to the surface electric cable leading to the switchboard. The junction box, in addition to connecting the two cables, vents any gas to the atmosphere which might reach the junction box through migration of well gases up the ESP cable. This venting eliminates the danger of fire or explosion, since the gas does not reach the switchboard. It also possible the test the electric components downhole from the junction box (Takacs, 2009).

The switchboard is the control center of a conventional ESP installation and functions as a motor controller. From the switchboard it is possible to control the on/off switching of the ESP equipment to the power supply using high capacity switch disconnectors. It also protects the surface and downhole equipment from many problems, in addition to monitoring and recording the most important operating parameters (Takacs, 2009)

2.2.2.7   Variable Speed Drive

The variable speed drive is, when used in ESP operations, installed between the power supply and the ESP motor. Running a conventional ESP at a constant speed is not very flexible compared to other types of artificial lift. When operating an ESP pump outside of its narrow recommended operating window the systems efficiency will be reduced and also lead to early equipment failures. By installing a VSD, variable speed drive, it is possible to change electric

frequency. If the pump is driven by a 60 hertz power supply and its recommended range is between 2.400 and 4.600 barrels per day, it is possible by regulating the frequency from 40 to 70 hertz to get a much wider range of flow rates, approximately from 1.600 to 5.400 barrels per day. To regulate the frequency, there is installed a step-down transformer between the Power supply and the VSD and a step-up transformer between the VSD and the ESP motor.

2.3 ESP published experiences

2.3.1 World's deepest through-tubing ESP

ConocoPhillips Alaska developed the TTCESP, Through-Tubing Conveyed Electrical Submersible Pump, technology in order to replace failed ESP pumps rapidly and economically, because conventional ESPs require expensive workover rigs to replace the component that fails most frequently, the ESP pump. In the newly developed system, the system components, electrical cable, motor and seal sections, was deployed conventionally by a rig. In addition they deployed a special latching device for the pump. The pump can then be pulled and replaced with wireline or coiled tubing and it eliminates the requirements of a rig.

The technology was originally developed to be used for 7 5/8 inch cased wells, and it was believed that it could not be used at Milne Point field in Alaska, because the here the wells were smaller, 7 inches. At the Milne Point Field there are 152 oil producers, where 104 wells have an ESP installed. Even though ESPs provide high drawdown and increased production, there are also some major disadvantages. Low solids tolerance, limited reservoir access and the most important disadvantage is that if one component fails the whole unit must be replaced. At Milne Point the ESPs were replaced out approximately every 3.5 years. The reason why they wanted to use TTCESP at this point was mainly to reduce operational costs, because of high rig costs, limited rig availability and declining oil rates.

The first step they took was to analyze the historical causes for rig workovers, RWOs. In the analysis it was shown that pump-related RWOs accounted for 50.85 %, while well-related RWOs accounted for 23.73 %, which were the two biggest problems. The analysis also showed that reducing the cost of pump changes would have the biggest impact on operations costs, compared to increasing the pump life. They then started to evaluate alternative methods of ESP deployment, such as coiled-tubing deployed ESPs, dual ESPs, cable-deployed ESPs and TTCESPs. Initially they thought that the easiest solution would be to use coiled-tubing deployed ESPs, since they at Milne Point already had over 400 coiled-tubing interventions per year. But since they had experienced corrosion problems with earlier CT, coiled-tubing, deployed ESPs they chose to use TTCESPs. With the TTCESP they could change the pump as many times as necessary until the integrity of the tubing-deployed components were compromised.

The next phase was to check if Milne Point had enough TTC-candidates, in order to find out whether or not they should develop the TTC technology for the 7 inch completions. Earlier the TTC-technology had only been used on 7 5/8 inch completions. The ideal candidates would be wells that produced between 600 and 6000 barrel per day with low deviation in the well and no severe doglegs. They found 91 candidates of a possible 130 ESP wells. They specially designed low-clearance clamps to fit on the ESP pump, in order to downsize the

TTC-technology fit smaller completions. In November 2009 the first TTCESP was deployed in Milne Point, which was the world's deepest TTCESP run at the time. Only a few months later, they deployed another TTCESP in the Kuparak field, which almost doubled the world depth record.

The modifications they needed to do in order to deploy the completion inside the 7 inch casing included a short wellhead spoolpiece, low profile clamps and modified RWO procedures. The TTC pumps they used at Milne Point Field can easily be up-sized or down-sized to optimize for production rate changes. After the successful deployments, all ESP-lifted wells at Milne Point are now being considered for TTCESP technology when they have an ESP failure. As of 3 March 2011, the first well has 468 days' run time and the second well has 245 days' rune time (J.Y.Julian, 2011).

2.3.2   ESP performance on the Mubarraz Field

The Mubarraz field is located in the southern part of the Arabian Gulf off the coast of Abu Dhabi and the field started production in May 1973. Some of the wells experienced a rapid decline and artificial lift or IOR methods became necessary. The ESP was selected as the most suitable recovery methods, because other artificial lift methods would require more space for facilities, in addition to that oil production with high water-cut was inevitable and higher lifting capacity was required, all the reservoirs in the Mubarraz Field are undersaturated and contain low solution GOR, Gas-Oil Ratio. The only disadvantage of using ESPs was higher operation costs due to workover jobs because of ESP failures.

Since they started using ESP in the Mubarraz Field, they have logged, monitored, investigated and improved the ESP they have used. For the pumps, intake gas separators, protectors and motors they have found solution on how to improve the lifetime of the components and how to prevent failures.

The pump they chose was a floater-type pump because the impellers material was a thermoplastic component called Ryton. They chose these Ryton impellers since they give dimensional stability against high temperature, chemical stability, corrosion resistance and they weighed less. The corrosion environment for the ESPs in the Mubarraz field is very severe, so the Ryton impellers were more suitable then conventional corrosion resistant metal. Another factor in the pump is the shaft stability. If the shaft were to vibrate in either radial or vertical direction, it could cause major ESP failure, and thus diminish the ESP lifetime. The team at Mubarraz field, chose to go with the ES-pump, Enhanced Stability, which uses ARZ shaft bearings. The ARZ shaft bearings main parts are solid zirconia ceramic bearing paris, and was chosen because of its high strength shaft which is high corrosion resistant and gives high strength for high torque.

For the gas separators the team chose reverse flow type, because of the corrosive environment on the Mubarraz field. Both the intake and the gas separator was ARZ in order to increase the reliability of shaft stabilization.

The high load thrust bearings were chosen for the protectors, because they can withstand high load and high temperatures, maximum 300 degrees Fahrenheit. The thrust bearing also

include a tilting pad system made of Hi-eX polymer to increase the reliability of the thrust bearing. For the seal section, they had two choices, bag-type or labyrinth-type. They chose to use the labyrinth-type seal, because the bag type could not be applied in the high pressure and high temperature environment on the Mubarraz field.

Since the motor in an ESP cannot be maintained after installation in the well, the reliability of motors is very important and can be a big impact on ESP lifetime. They decided to use a new insulation system. The used AIS, Advanced Insulation System, which use PEEK, polyetheretherkepton, insulation without varnish. The AIS is hydraulically stable, oil-resistant and abrasion resistant and its lifetime is expected to be more than 7 times longer than the previous insulation system used on the Mubarraz Field.

After all the improvements that were done on the ESPs the average lifetime went from 2.12 years to over three years. The current problems to be solved are ESP failures due to well conditions. Detailed inspections of the ESPs after a failure are significantly effective to prevent future ESP failures (Masahiro Miwa, 2000).

3 ESP Screening Tool

This chapter will describe how the tool was made and how it functions.

This ESP screening tool is designed to do a rough screening of wells considered for an ESP installation. The program is doing the screening of the wells by calculating the difference in production with and without an ESP in the well. The difference in production plus the cost of installing, removing and running an ESP will determine if the well gets a positive net present value. The results from this screening tool is only meant to give an indication of whether or not an ESP should be installed in a given well. To determine if an ESP should be installed in a well, more calculations needs to be done. This ESP screening tool was made possible due to an integration-tool from Statoil, which made it possible for me to create the ESP screening tool in C#. The Screening Tool is to date not completely finished, but it is possible to run wells through the program and get results. To this day, 10 wells have been screened and the C#-program consists of 1800 coded lines.

3.1 Overview of the ESP Screening Tool

The screening tool is inputting and outputting data to four different components as can be seen below. The four components connected to the C#-program or the ESP Screening tool is two databases, Prosty and the casing string design, a simulation program, Prosper, and the user of the program, which in this thesis are the default values.
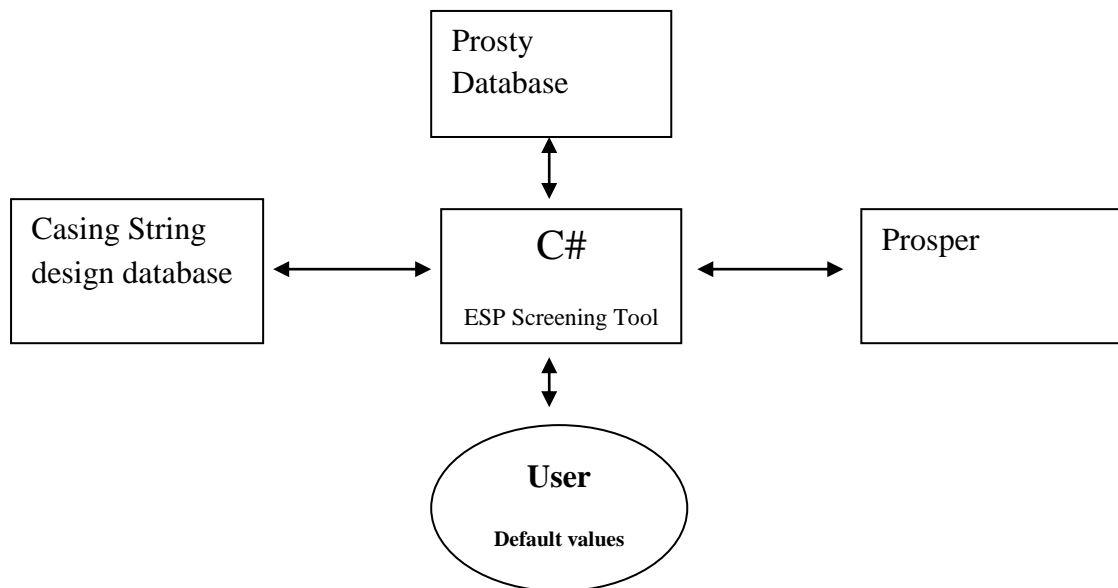
The Prosty database contains production and perforation data for all the wells the program screens. This database is updated daily with new production data. From the Prosty database the program collects oil and water production and top perforation data. The second database in use is the casing string design or CSD database. This database contains the full casing and tubing setup of every well and also survey data. This database is not updated daily, but updated for every new well or change in the setups. From the CSD database the screening tool retrieves casing-, tubing- and survey-data. The next part the program inputs and outputs data

to is Prosper. Prosper is a well performance, design and optimization program for modeling most types of well configurations found in the worldwide oil and gas industry today (Petroleum Experts). From Prosper the program retrieves the variables needed to calculate the design rate, in addition to the applicable pumps and their efficiencies. The input to Prosper is the variables needed to do an ESP design. The last part of the equation is the user. Since the program is not user friendly at this point, where the user can input data themselves, the user in this sense will be the default values within the program. The default values are the discount rate, installation-, running- and removal cost of the ESP, the oil price and the wellhead pressure to the program. The output to the user is the well-name, the applicable pumps and their efficiencies, whether the fluid production was estimated or given an assumed decline of 10 percent and the net present value, NPV.

The NPV value calculation is shown and explained on the next pages. To find future values for fluid production with and without ESP and future water cut values the program estimates new values based on production and water cut values retrieved from Prosty. The values used in the net present value calculation are shown in Table 1: Inputs to the net present value calculation.

Input to NPV	Explanation
q_o	starting rate from production estimation
q_{ESP} / q_{design}	starting rate w/ESP
D	D-value from production estimation
c0	constant from water cut estimation
c1	constant from water cut estimation
P_i	Installation cost of ESP on platform
P_r	Running cost of ESP per year
P_{rem}	removal cost of ESP
P_o	Oil Price
k_d	Discount rate

Table 1: Inputs to the net present value calculation

NPV CALCULATION

Is the well self producing?

Assumption: The well is self-producing if more than 10 % of the production values for the last three years are not 0.

YES →

NO →

Is the D-value from the production estimation greater than zero?

Is the D-value from the production estimation greater than zero?

YES → **NO** →

YES → **NO** →

Path 1:

Calculates future fluid production with and without ESP, using the estimation formula.

Path 2:

Calculates future fluid production with and without ESP, assuming a 10 % decline in production per year.

Path 3:

Calculates future fluid production with ESP using the estimation formula.

Assumes that we have no production without ESP.

Path 4:

Calculates future fluid production with ESP, assuming a 10 % decline in production per year

Assumes that we have no production without ESP.

The program writes the calculated net present value to screen

The flowchart above gives a short overview of the net present value calculation. The ESPs lifetime is assumed to be three years. When doing the final calculations, finding the actual NPV for a well, the program has four different paths to take. Path 1 and 2 will be used if the well is considered as a self producing well. Path 1 will be chosen if the D-value from the production estimation is greater than zero, and path 2 will be chosen if the D-value is smaller than zero. Path 3 and 4 will be used if the well is not considered as a self producing well. If the D-value is greater than zero, path 3 will be chosen, if not path 4 will be chosen. If the program uses path 2 or 4, it assumes a 10 percent decline in fluid production per year.

Last the program writes the result, the NPV, out to the screen before it starts on the next well.

3.2   ESP Screening Tool C#

As mentioned this tool was possible to create, because I was given an integration tool that helped me build this tool in C#. This integration tool helped with connecting to databases, such as Prosty, production database, and CSD, Casing String Design database, making it possible to retrieve real-time production data and tubing, survey and casing data. The tool also helped with connecting to Prosper, a simulation program, and helped writing data to Excel. The queries made to the databases are done using SQL, Structured Query Language. SQL is a query language used for accessing and modifying information on a database (Techterms).
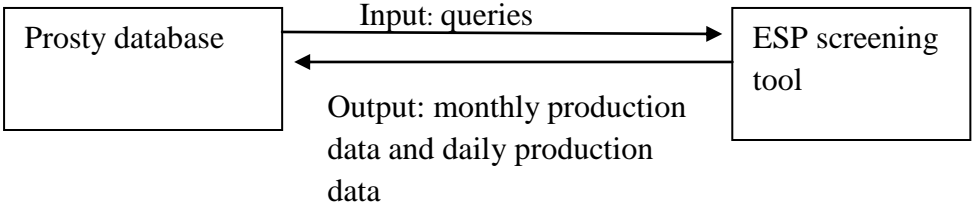
The first query is to retrieve a list from Prosty with the names of all wells that is defined as an oil producer, OP. The list is then stored in a string, and the program will evaluate all of the wells in this string, using a for-loop. This query and the for-loop will make it possible to use the program in the future without doing changes in the program. If new wells are drilled and added in the database, this well will automatically be evaluated when the program is being run. This crucial part of the program is to date not fully implemented, due to the fact that some wells has slight differences compared to other wells, and all of these differences has not been addressed yet. The coding is included in the program. Instead of utilizing this coding, the program has been given a string of wells to evaluate.

From this point on, all the coding is in a for-loop that will evaluate the wells separately.

The next part of the program is writing the well-name to the command-window, so the user can see which well is being evaluated as the program runs. To have the right name to input in later queries to Prosty and CSD, the program has to investigate which form the well-names have. The well-names the program considers are written on this form: letter-dash-number-number. If the third entry is a 0, this must be altered to do a correct query in CSD. If a well is called "X-03", and the program do a query with this name in the Casing String Design database, the program will get zero results. In Prosty this will work, but in CSD the form of the well-name must be "X-3". To create two well names for the same well if needed, the program has an if-loop that checks if the third entry in well-name is a 0, and creates one well name one with a zero in the third spot, and one without.

Next the program has two queries to the CSD database, one query for survey data and one for casing data. Both of the queries will only retrieve one name. For the survey data query we want to find out which well name that have the deepest measured depth and the program

saves this name as "survey_name". For the casing data query we want to find which well name that has the deepest measured bottom depth and save it as "casing_name". The reason the program does these queries is because the well being considering can have multiple names, such as "X-03 A" or "X-03 T1". The assumption here is that the well-name with the deepest depths registered, is the most accurate to use. This is done because in the beginning of this project, there was some trouble that the survey data and the tubing data did not correlate with inputted depth data in the Prosper models and it was not possible to proceed with the evaluation.

```
┌─────────────────────┐     Input: queries          ┌─────────────────────┐
│                     │ ──────────────────────────> │                     │
│  Prosty database    │ <──────────────────────     │  ESP screening      │
│                     │                              │  tool               │
└─────────────────────┘     Output: monthly production └─────────────────────┘
                            data and daily production
                            data
```

The next query is retrieving monthly data ranging back three years. The data being collected is start- and end-time of the month, average wellhead pressure, ideal fluid production, fluid production, up-time in percent, max hours in the month and water cut. The water cut is the percentage of water to the total fluid production. The difference between ideal fluid production and fluid production, is that the ideal fluid production, water and oil, is divided by the up-time in percent. The up-time is the percentage of producing hours per day to the total hours per day. This is done in an attempt to take down-time on the rig out of the equation. All of this data is collected from the Prosty Database. This data is for the user to check after the program is done. The data retrieved in this query will not be used in the program, it will only be written to excel.

After the monthly Prosty-query, we retrieve the daily ideal production of fluid and its corresponding date for the last three years. The daily ideal fluid production is the same we got in the last query, except here we are getting the daily production, not monthly production. These data will be used to determine whether or not we assume the well is non-productive. It will also be used to determining future production with and without an ESP. This query will be saved within the program in the dataset "Day_Prod".

The last query we do to the Prosty Database is stored in a dataset called "WC_vs_prod". Since we are retrieving fluid production and not oil production, we need the water cut to find oil production later in the program. In the start of this program, it retrieved water cut versus time. The problem with these values was that the program can't use the same WC values for future production with ESP and without ESP. This is because if we have a higher production after installing an ESP and use the same WC value for both ESP-production and normal production, the total water cut for ESP production will be lower than for regular production. By estimating water cut versus accumulated production instead of water cut versus time, the increased production due to an ESP will give higher water cut values compared to production without an ESP.
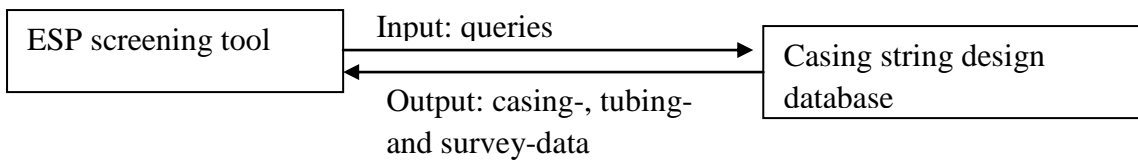
The next queries in the program will retrieve distinct tubing outer diameter, OD, survey list and casing list. The first query will be saved in dataset "Well_tub_OD" and will give a list of all tubing outer diameter sizes in the well, sorted after descending outer diameter. This list will be used later in the program to retrieve the corresponding inner diameters and depths. To do this query and get the values the program is looking for, it needs a specific variable that separates the tubing data from the other data in the CSD. To separate the tubing data from the rest of the data the program asks the CSD database for the symbol "4".

For the survey data, the program uses the survey name it found earlier. This query retrieves all measured depths and corresponding true vertical depths values that had the name "Survey_name". All this data is saved in the dataset "Survey_list". The last of the three CSD queries is getting the bottom depth and the inner diameters for all casings with well identification equal to the outer diameters in "Casing_name".

The next part of the program, writes all results from the queries to excel. This part does not need to be in the program, because the program is not retrieving any data from excel. Instead the program is storing the data from the queries in datasets within the program. The reason why all the results are being written to excel is that in the start of the programming is to give the user a way to check the data. At start it was also used to check that the program was retrieving the correct data.

After the excel-workbook is saved and closed, the program creates three new arrays from the dataset "WC_vs_prod". One for all the production values, one for all the water cut values where the water cut values are greater than zero or smaller then one, and the last variable is for all the production values where the corresponding water cut values are greater than zero or smaller than one. The program names these variables "Check_table", "WC_table" and "Prod_tabell". Next the program checks if the number of values in "Prod_tabell" is bigger than ten percent of the number of values in "Check_table". If this assumption is false, the program will consider the well as a non-productive well, and a logic variable "Self_prod" will be declared as false. Later in the program, this logic variable will make sure that in the net present value calculations there will be no future production without ESP. In this if-loop the program initializes start-values for further calculations. "Start_prod" is the last value inputted in the variable "Prod_tabell", and "Start_WC" is the last value inputted in "WC_table".

Some of the constants that have been declared will be used later in the program, especially in the net present value calculations, have been set to a default value. Some of these values have been based on relevant data or discussions with professionals, and others have been set to what is thought to be a reasonable assumption. Among the values which have been based on relevant data or discussions with professionals is installation cost of ESP on a platform, running costs of ESP, removal cost of ESP, maximum gas liquid fraction at ESP depth and average production decline per year. Those who have been set as a reasonable assumption is among others discount rate and oil price.

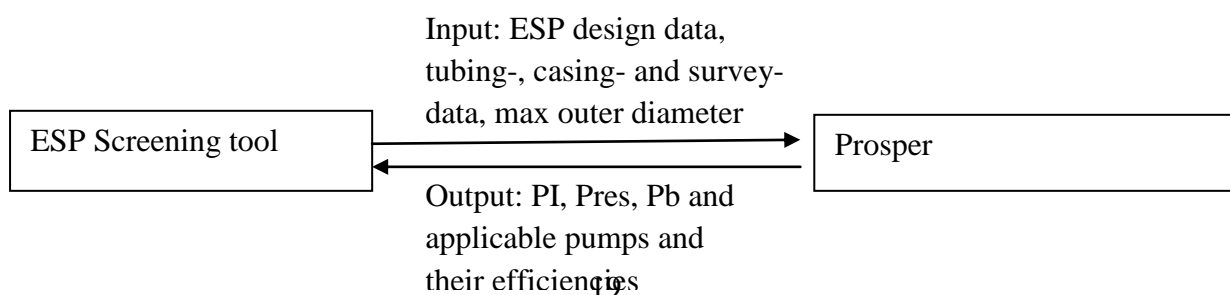| ESP screening tool	Input: queries →	Casing string design database

Output: casing-, tubing- and survey-data

The tubing outer diameter data that the program collected from the casing string design database, needs to be checked and sorted properly before it can be inputted into Prosper. First the program retrieves the corresponding tubing inner diameters and depths, and inputs them in an array. Next the program sorts the data so they are descending, greatest values to smallest values, based on the depths. After that the program checks that we have no mismatch in the diameters. Because the program retrieves the tubing data the way it does, it sometimes happened that the tubing diameters were not sorted correctly. Since the data was sorted after descending depths, so should the diameters. This problem was solved by using a for-loop that checks every line in the array. The way it works is that for every line in the array the for-loop checks the next line to see if the diameter on the next line is bigger than the diameter on the line the for-loop are on. If the next diameter is bigger than the line the program is on, the program assumes that the next entry is false, and this line will not be written to the new array the program are creating while the for-loop runs. By checking and validating the data like this, the program assumes that the first line in the array is correct.

The survey-data in the dataset "Survey_list" is now being copied to two new arrays, one for measured depth and one for true vertical depth. The program is also making two new variables, one for the length of the arrays, and one that is the number of inputs, which is the length of the array divided by eighteen, which the program will use later when it is inputting the survey data in to Prosper.

The last thing the program does before it starts inputting values and simulating in Prosper is to sort the casing data. From the results of the query the program did earlier it copies the data from the dataset into two new arrays, one for casing depth and one for casing inner diameter. The program checks that all the entries have inner diameter values and if some does not contain any values, the program starts a for-loop to search through the array and copy entries with values to a new array.

3.2.1   Prosper: Simulation and calculation

Prosper can be used for modeling many events among others ESP-installations, which is what the program uses it for. For the wells being considered, the program has started with older well-models where the input data has been generated by other users, and the program has inputs recent data where it is possible. Some of the data in the older models has been used because the program has not any recent data or it got no better assumption. In order to use the data the program have retrieved and inputted to Prosper, the screening tool has used OpenServer to connect to Prosper.

Input: ESP design data, tubing-, casing- and survey-data, max outer diameter

ESP Screening tool	→	Prosper

Output: PI, Pres, Pb and applicable pumps and their efficiencies

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The first thing the program does in Prosper is to set the artificial lift method to "2", which is defining the artificial lift method for the well to be electrical submersible pump. The program then inputs the updated data, water cut it has retrieved from the Prosty database and the casing string design database. The program starts with the survey data, where the program has twenty inputs each for measured depth, MD, and true vertical depth, TVD. The program starts by setting the first entries to zero on both the measured depth and the true vertical depth. Then it starts a for-loop which will input eighteen values for both MD and TVD. The last entry of survey data is the last value in both the MD-array and the TVD-array.

Next the program inputs the tubing data. Here, in addition to inputting depths, inner diameters and outer diameters the program also have to declare what sort of tubing it is inputting, whether it is X-mas Tree, tubing or liner. A X-mas Tree, or a Christmas Tree, is an assembly of valves, spools, pressure gauges and chokes fitted to the wellhead of a completed well to control production (Schlumberger Oilfield Glossary). A liner is the production tubing in the bottom of the well. After the program has inputted all the tubing values, and since Prosper have a maximum input of twenty tubing values, the program sets the remaining tubing values in Prosper to zero.

Before the program can start inputting values to the ESP design, it also have to input the casing inner diameters, and since these values is inputted in the same chart as the tubing values, it has to match the tubing and casing depths in order to get the right inner diameters at the right place. This is done by using a dual for-loop with an if-loop within the for-loops. For each entry of tubing inner diameter the program checks each casing data. If the corresponding casing depth is deeper than the tubing depth, and the casing inner diameter is bigger than the tubing outer diameter, the program inputs the casing inner diameter. If these conditions are not met, the program inputs a value that is 1.2 times the value of the tubing outer diameter. This is done because there has to be a value for the casing inner diameters in the chart that is bigger than the tubing outer diameters, or else the Prosper simulation will fail. Before the ESP calculations is initiated the program checks that the depths of the geothermal gradient, the tubing data and the survey data correlate.

In order to do ESP calculations in Prosper, the program needs to input values in the ESP chart. First off the program acquires all the variables it needs. Some of them are assumed, such as the wellhead pressure and the frequency that the motor will be run at. Other variables are procured from the databases, such as the depth chosen to place the ESP and the water cut. Since this program will do calculations on the wells automatically, the ESP depth is set to be the top perforation depth minus 300 meters as a default value. To find the design rate for the ESP, the program uses formula 1.

$$Q\_design = PI * (Pres - Pb) \qquad\qquad\qquad (1)$$

PI, m3/bar^2/d is the productivity index, which is a measure of how much fluid a well can deliver per bar squared per day. Pres is the reservoir pressure, and Pb is the bubble point pressure. Q_design is the programs chosen design rate. This assumption is very conservative, because it assumes that the well does not contain any gas. Some ESPs can withstand up to 15 percent gas at the pump intake, and some of the wells the program is doing calculations on

now are already producing oil with an amount of gas right now. The PI, Pres and Pb are all retrieved from the Prosper model for the well. For these data the program does not have any better assumption. Before going to the next step the program inputs all the variables into Prosper.

When doing the ESP calculation, the program has a for-loop that can calculate the design rate at a given gas liquid fraction at ESP depth. This part is only done if the well is considered to not be producing and the bubble point pressure is higher than the reservoir pressure.

After the ESP calculation is done, the program retrieves all the applicable pumps and their efficiencies that can be used on the given ESP. These pumps are then sorted after the efficiency and written to the command-window. The Prosper model is then saved and closed.

3.2.2   Calculations
Before the calculations starts, the program declares and initializes all the variables and arrays the program needs and some are given values, such as yearly decline of oil, ESP removal cost and ESP running cost. The program also calls on the estimation algorithms, one for future production with and without ESP and one for water cut.

3.2.2.1   Production estimation
To do the production estimation, the program uses Arp's Exponential Decline Formula (Curtis H. Whitson), formula (2), to estimate two values, q_{0i} and D, based on the daily fluid production data for the last three years retrieved from the Prosty database.

$$q,o = q,oi \times e^{-D \times t} \qquad\qquad\qquad\qquad (\,2\,)$$

In formula (2), q_0 is the rate at time t, q_{0i} is the initial oil rate, D is the decline constant and t is time.

The Arp's Exponential Formula is meant to be used on estimating future oil production, not liquid production, which it is being used for by the program. This assumption has been validated by a professional (Høgstøl, 2012). The estimation is based on older real-time data from the well the program is currently evaluating. These data has been collected from the Prosty database and are going three years back in time. The estimation is not weighted, which means that every data point is valued equally.
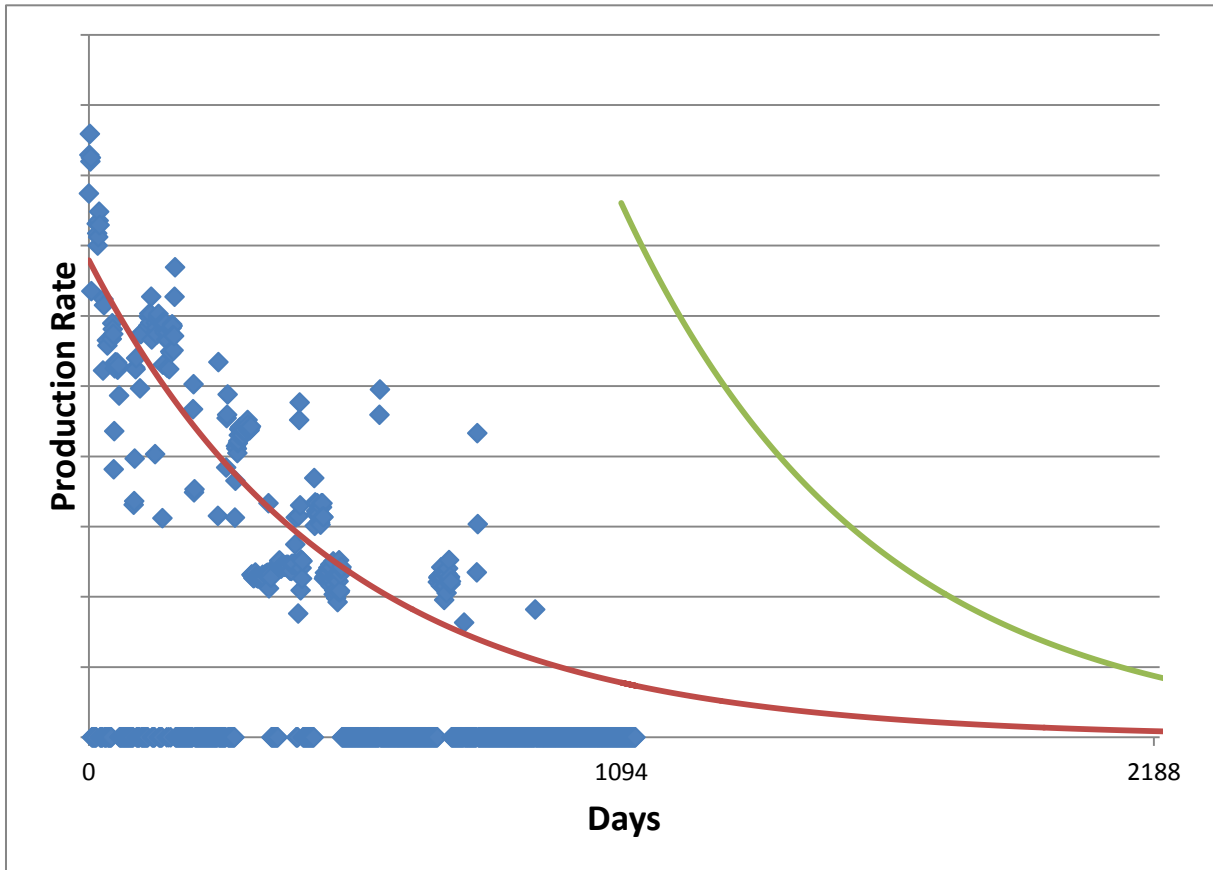
Figure 4: Production graph shows the different fluid production rates with and without ESP installed. The blue dots are the real-time data used to find the constants q_{0i} and D, the green line is future ESP production and the red line is the production without ESP. The red line starts at year 3, day 1094, according to the graph, but in the program this is declared to be year 0, since the program does not do any calculations before this point. The area between the green and red line, from day 1094 to day 2188, is the increased production because of ESP. This increase production will be the basis for the net present value calculation.

3.2.2.2 Water cut estimation

Since the program is retrieving the fluid production, and not the oil production, from Prosper, it needs to estimate the water cut to find the oil production. The program is basing the estimation on water cut versus accumulated production, in order to get different water cut values for ESP production compared to regular production. If the program had based the estimation on water cut versus time instead, the ESP production and the regular production would have been given the same water cut values, which would have resulted in smaller total water cut for the ESP production compared to regular production.

To do the estimation, the program uses formula (3) to calculate the water cut values. By using this formula the program is certain that the estimated water cut values will not exceed one. Figure 5: Different water cut formulas, shows the different formulas that were tested, in order to find the most suiting formula.
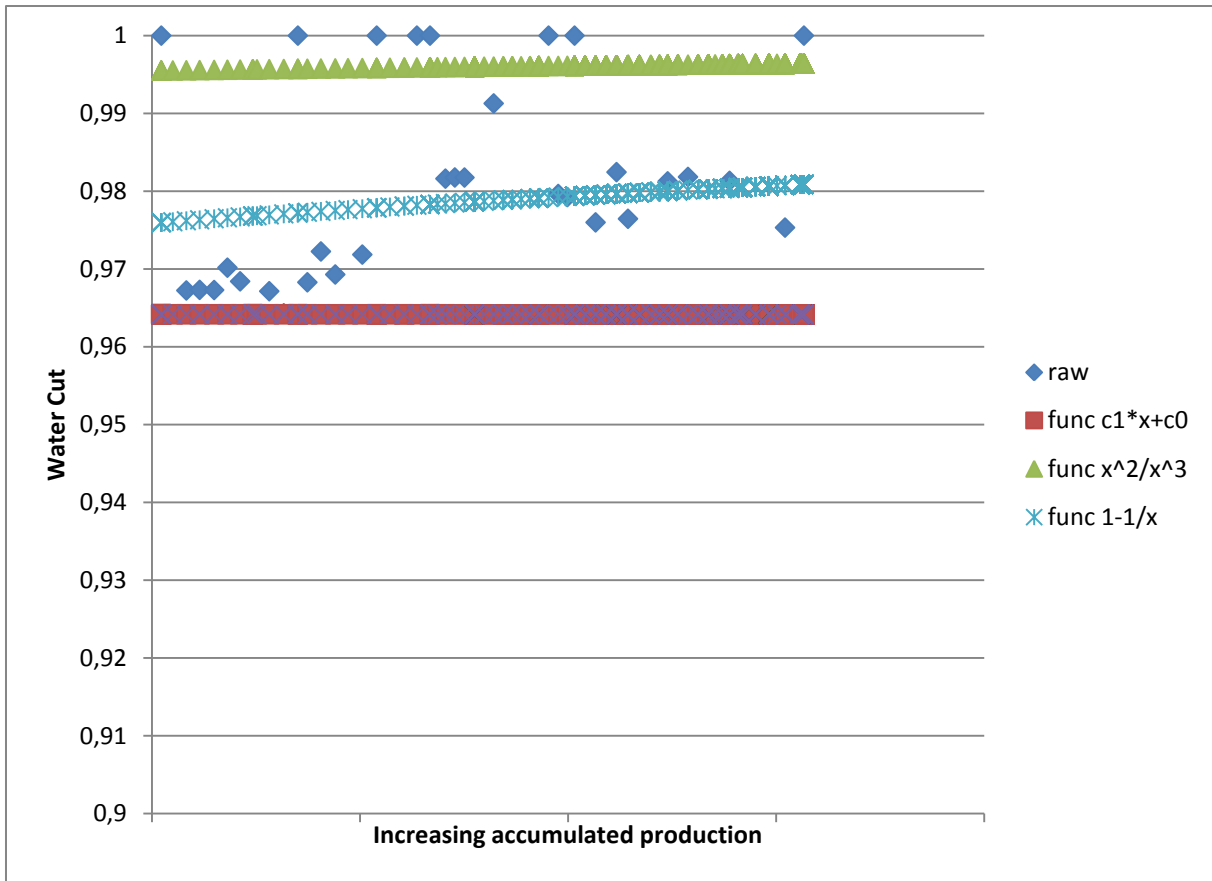
Figure 5: Different water cut formulas

The blue dots are the real-time data collected from Prosper. The formula, (3), that was chosen is the light blue line. The reason it was chosen is that this line match best with the real-time data.

$$WC = 1 - \frac{1}{c(0) \times prod_{acc} + c(1)}$$ (3)

In this formula c(0) and c(1) are constants that is determined by the algorithm, and prod_acc is the accumulated production. The accumulated production is the accumulated production from the Prosty data used in the water cut estimation plus the new future daily fluid production values calculated. Before the estimation, the program sends a query to prosper in order to get the real-time data it needs to do the estimation. All values with a WC-value greater than one or smaller than zero, and its corresponding production rates are excluded from the estimation.

3.2.2.3 NPV-calculations

First off the program checks if the variable "Self_prod" is true or false, as mentioned earlier. If this variable is true, the program does calculations with and without ESP, and if it is false, the program assumes that this well is not producing by its self and will have no production without ESP. The ESP lifetime is assumed to be three years.

3.2.2.3.1 Path 1

Next there is an if-statement that checks if the D-constant from the production algorithm is greater than zero. The reason that this if-statement is implemented is because if the D-value is smaller than zero, the new future production will increase with time, which is believed to be a weak assumption. If the D-value is smaller than zero the program assumes a ten-percent decline per year.

If the D-constant is greater than zero, Path 1 will be chosen and the program calculates the daily future fluid production with and without ESP, using the Arp's Exponential Formula (2). For daily future fluid production with ESP the program uses the calculated design rate, Q_design, instead of the estimated starting rate. The time variable will go from 0 to 1094 days, which represents the three years the ESP is expected to produce. The estimated starting rate will be used to calculate daily future fluid production without ESP. Here the time variable will go from 1095 to 2189. This difference is a caused by where the starting point of the estimation is. For ESP production the starting point is when we install it, but for production without ESP the starting point is the oldest data, minus three years, that were used in the estimation. If the program had calculated production without ESP with the time variable ranging from 0 to 1094, the program would have estimated the values we retrieved from Prosty and used in the production estimation.

 Next the program finds the daily water cut values with and without ESP, based on the constants from the estimation and daily accumulated fluid production. By multiplying the future daily fluid production values with one minus the daily water cut values, as shown in formula (4) for production with and without ESP, the program calculates new future oil production. By summarizing these values for each year we have production with ESP, three years, we find how much the well can, assuming our assumptions is valid, produce with and without ESP. Before the program starts including the discount rate, it finds the yearly difference in production with ESP and without ESP.

$$Oil.prod = (1 - WC) \times fluid.prod \qquad\qquad (4)$$

When the ESP Screening Tool is summarizing all the values, it starts at year 0 and it adds the installation cost, which is assumed to be 100 MNOK (Vinge, 2012), as a negative value. For the years 1 to 3 it uses formula (5).

$$Sum(year\ X) = \frac{(diff.prod.oil \times oil.price) - running.cost}{discount.rate^X} \qquad\qquad (5)$$

The oil price is assumed to be 4000 NOK/Sm3 (Vinge, 2012), the running costs are set to be 1.5 MNOK/year (Vinge, 2012) and the discount rate is set to be 12 percent. In year 3 the program adds the removal cost of the ESP, set to be 25 MNOK (Vinge, 2012), divided by the discount rate in the power of three. The last calculation the program does is to summarize all these values. Path 1 was used on three wells in this thesis.

3.2.2.3.2 Path 2

If the D-value from the estimation is smaller than zero, Path 2, the program calculates future daily fluid production with a ten percent decline per year instead of using the D-value. For each of the 1095 days the program finds a future production it makes a "timefactor", formula (5). The program also calculates what the "total decline" will be for the 3 years, which is 0.9 in the power of 3. To find the new future production for each day, the program multiplies a starting production with the "total decline" in the power of "timefactor". The calculations are shown below in formula (6), (7) and (8).

$$timefactor = \frac{X}{total.days} \qquad (6)$$

X is which day being evaluated and "total.days" are the total amounts of days being evaluated. The program is set to find new production for three years, which is 1095 days.

$$total.decline = rate^{no.years} \qquad (7)$$

The rate is, as mentioned earlier, 10 percent per year. In order to use this in the calculations we set the rate to 0.9. Number of years represents how many years I want the program to evaluate, which in this program is three years.

$$future.prod = Start.prod \times total.decline^{timefactor} \qquad (8)$$

To find the future production we multiply a starting production with the total decline, 0.729 over 3 years, raised in the power of "timefactor". When the program calculates to find the new future production without ESP, the starting production is the last fluid production value, which is not 0, retrieved from Prosper. When future ESP production is calculated, the program uses the design rate, calculated in formula (1).

After calculating the future production, the program will, as in Path 1, calculate the accumulated production per day and find future WC-values for each entry. After calculating the future oil rates with formula (4), the program will use formula (5) in order to calculate the NPV-value of the well. Path 2 was used on six of the wells that were evaluated.

3.2.2.3.3 Path 3

If the "Self_Prod" variable is false and the D-value is greater than zero, Path 3 is chosen. The assumption here is that there will be production in the well without ESP. The program will do the exact same calculations as it did in path 1, with the exception of having zero production without ESP. This path was not used by any of the wells evaluated.

3.2.2.3.4 Path 4

The program will select this path if "Self_prod" variable is false and the D-value is smaller than zero. As the program did in Path 2, it will assume a yearly decline of 10 percent, but this time the program will only calculate the future production with ESP in the well. Out of the ten wells evaluated in this thesis, this path was chosen once.

3.3 Results

The ESP Screening tool ran through all the wells that it was given to evaluate. Out of the ten wells, the program used path 2 to calculate the net present value on six wells, three wells used path 1, one well used path 4 and no wells used path 3. The net present value results are shown in Table 2: ESP Screening Tool results.

Well	Net present value	Prod. Calc. Method	Self Producing
Well 1	-134896,12	10 % decline	yes
Well 2	-59975,79	10 % decline	yes
Well 3	-130714,86	Estimated production	yes
Well 4	-1255691,81	10 % decline	yes
Well 5	-105749,32	10 % decline	yes
Well 6	-68804573,70	Estimated production	yes
Well 7	-95127,26	10 % decline	no
Well 8	-783362,78	Estimated production	yes
Well 9	-22332,82	10 % decline	yes
Well 10	-75615,51	10 % decline	yes

Table 2: ESP Screening Tool results

The net present value is given as the fraction of the starting production rate of ESP. A full calculation for well 2 can be seen in Appendix A: Net present value calculation of well 2.

4   Discussion

This part will consider the assumptions made in the ESP screening tool, look at the programs user friendliness and look at how the program can be improved further.

4.1   Well challenges

When a well is being drilled, the well path is rarely straight. A lot of changes in the azimuth and the angle create many dog-legs in the well. When determining where to place an ESP, the well path is in the calculation. The ESP can be up to 80 meter long, and in order to make it function at maximum capacity it should be place in a part of the well where there are no dog-legs. The program does not take this into the equation. Since the program is run automatically, I decided that it is better to assume that where the ESP is placed is a straight path. In order to fix the problem and implement it the program, the program had to investigate each well in order to find a straight path in the well-path, where there is no dog-legs at all. Since this program is only a rough screening, I decided that the assumption is valid and used it.

Gas break-through in the well can cause problems top-side and minimize the oil production. When doing a final investigation of whether or not to install an ESP in a well, the gas-oil-ratio, GOR, must also be investigated. When the program calculates future production, it has only looked at water and oil production, not gas production. If the program in the future is being improved, this should be implemented. One way to check if the well will get a gas break-through is to retrieve the gas production, in addition to the oil-production, from Prosty. By plotting the real-time GOR-trend, it is possible to get a hint if we will have a break-through or not. It is also possible to use the estimation for production and find the future gas production. This new production might not be completely valid, but it can give an indication if the production of gas will increase. In the program I have only looked at the gas-liquid-fraction, GLF, at the ESP setting depth, which is top perforation minus 300 meters. I have a maximum GLF parameter set to 10 percent in the program and after the ESP-design is done in Prosper, it checks if this limit is reached. This is done before I do calculations on future production. The assumption that none of the wells being considered will have a gas break-through is not very strong. Some of the wells being considered are already producing some amounts of gas.

4.2   Production and down-time

While producing oil from a well, we must consider that it is not possible to produce 100 percent of the time, due to unforeseen circumstances or scheduled shut downs for maintenance. This down-time, as it is called, are calculated as hours not producing divided by total hours a day. Down-time can also occur because of low pressure in the reservoir. We then get what is called "Cyclic Production" where we produce some days, shut down the well, wait until pressure has been rebuilt in the reservoir, and then open the well to produce some more fluids. The production data I chose to use in this program, for the production estimation, has not taken down-time into consideration. When the program retrieves its production for the current well, this data has been divided by up-time, hours producing in a day, and multiplied by twenty four, the total hours in a day. The reason for doing this is that I wanted to do calculations in ideal conditions, where we have no down-time and the wells are producing

24/7. This assumption is not very strong, because in the future we can't expect to have less down-time than we already have now. Also when the reservoir gets older and starts to produce smaller volumes, more injection- and production wells might get drilled in order to produce more oil and gas or other IOR-measures, Improved Oil Recovery.

In the NPV-calculations, I use the variable "Self_prod" in order to separate self producing wells from non-producing wells. The assumption is that if the well has fewer production days than ten percent of the last three years, the well is not producing. The reasoning behind this assumption goes as follows. We can separate the wells in three different categories: Self producing wells, where the reservoir has high pressure and produce fluids continuously, cyclic wells, where the well produce for a couple days before it is shut in to rebuild the pressure in the reservoir and then starts to produce again, and non-producing wells. Since this program is run automatically and is built to evaluate several wells at the same time, I decided it would be too much work to look into the production data for each well and determine whether or not the well should be considered a non-producing well, a cyclic well or a self producing well. This is because even the self-producing wells have down-time due to maintenance, and to figure out what is maintenance down-time and what is down-time due to too low pressure in the reservoir, would be too much work. Instead I assumed that I was only looking at two different well-producers, self-producing wells and non-producing wells.

When installing an ESP in a well, there is usually a shut-down on the field for approximately three weeks (Vinge, 2012). In addition when a decision of installing an ESP in a well has been taken, it usually takes around one year before the ESP is operational. None of these factors have been included in the program. In order to make a correct calculation, I would have to assume that we would produce one extra year without ESP and remove three weeks from the production with and without ESP, to take into account the time it takes before installation of ESP and the down-time during the installation of ESP.

4.3 Water cut estimation

As mentioned in chapter 3.2.2.2: Water cut estimation I chose to estimate water cut versus accumulated production instead of water cut versus time to retrieve different water cut values for production with ESP compared to production without ESP. If I had continued to use water cut versus time the ESP screening tool would have gotten the same water cut values with and with ESP. Since the ESP production is normally higher than regular production, the total water cut would be lower for ESP production compared to production without ESP. By estimating the water cut versus accumulated production instead, I get higher water cut values if the ESP production is higher than production without ESP, because the ESP is producing more fluids.

By looking at Figure 5: Different water cut formulas it is possible to see that the formula I chose is matching very well with the real-time data retrieved from Prosty. The problem with the water cut estimation is when I apply the formula to calculate future water cut values, and the ESP Screening Tool calculates high ESP production rate, the water cut values goes quickly towards one. This problem is shown in Figure 6: water cut estimation.
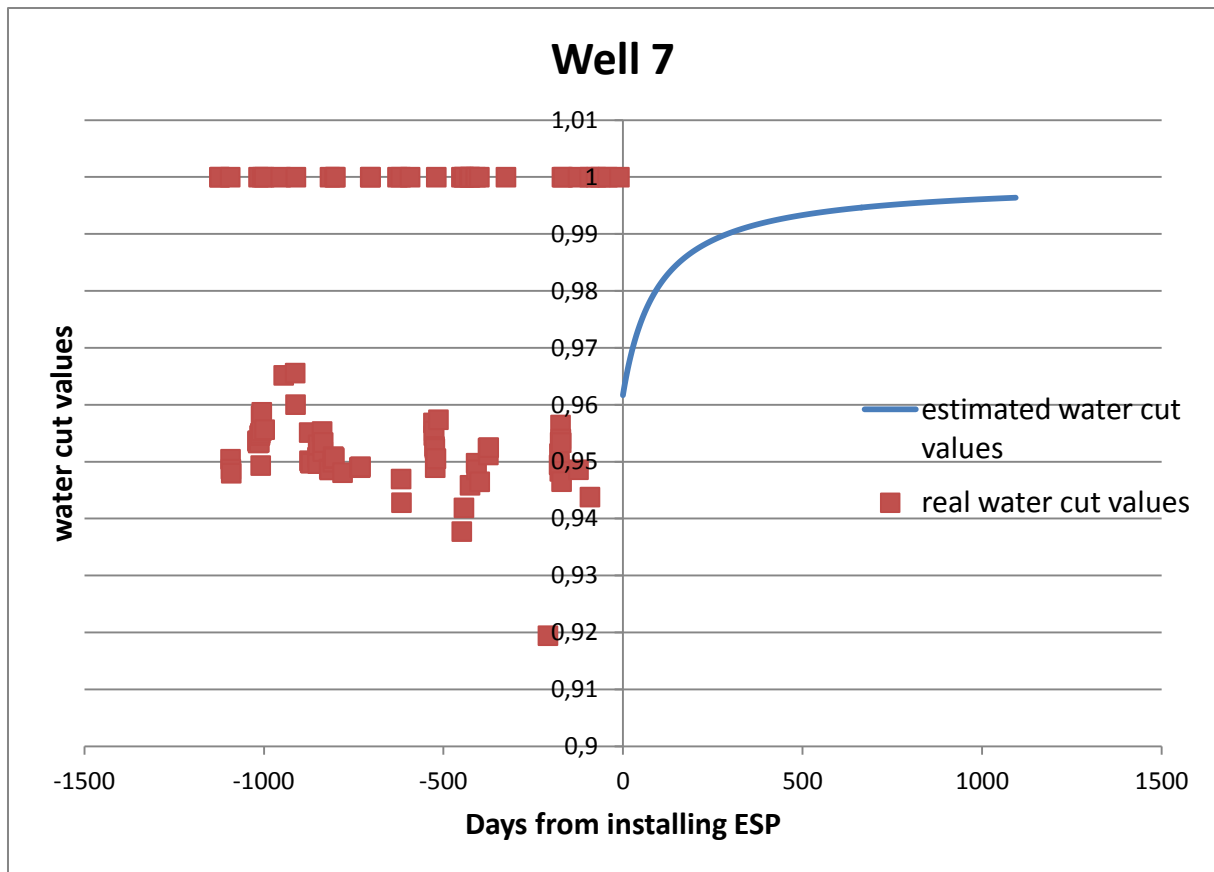
Figure 6: water cut estimation

I regard this as the biggest problem with the program to this date. For an assumed non-productive well with high estimated future ESP fluid production, the program will give very low oil production values, and thus giving a negative net present value. To further show how this affects the net present value calculation on well 7, Table 3: Varying net present value shows the difference in net present value with water cut estimation and steady water cut. The steady water cut is the last retrieved water cut value from Prosty.

Water cut method	Net present value
Water cut estimation	-95154,7468
Steady water cut of 0,9438	43859,6967

Table 3: Varying net present value

The net present value is given as a fraction of the starting ESP production rate.

4.4   Production Estimation

The production estimation, described in chapter 3.2.2.1 Production estimation, is not perfect. For the purpose of doing a rough screening of the well, it works, but it is possible to get a better estimation for the future production values. In the estimation I look at all of the fluid production rates from the three last years, but I remove all entries where there was zero production. In the estimation there is no weighting of the values, which there should have been. By weighting I mean that all the values used in the estimation is worth equally much. In order to get a more correct estimation, the production data that I use should be weighted. The

most recent data should mean more for the estimation than the data from three years ago. For one of the wells that have been evaluated there have been done some IOR-operations in the last six months, and the production has increased after this point. This increase should have continued in my estimation, if it had been perfect, but since I haven't used weighting in the estimation the trend is negative. The reason for not including weighting in the production estimation is due to the complexity of the coding that would have been required.

4.5   Prosper simulation

Most of the variables I have used has either been given to me by professionals or been retrieved from the real-time data. When the program calculates the design rate in formula (1), it uses the variables PI, Pres and Pb. These values were retrieved from previous Prosper models that other professionals had made. Since I don't know where they have gotten these data, or if they have only assumed them, I can't be sure of their validity. The reason I chose to use them is simply because I had no better assumption myself.

The assumption that the design rate the program calculates is correct is not very strong. This rate is calculated on the basis that the well does not contain any gas. And the assumption that the formula used to calculate the design rate, Q_design, is the best formula to use is also not very strong. The rate that the program calculates is very conservative. As mentioned in chapter 3.2.1 Prosper: Simulation and calculation ESP can, with the right equipment, fully function with as much as 15 percent gas in the well. The rate can also be limited by MSR, Maximum sand-free rate. If the calculated rate goes beyond the MSR, the well might have a sand avalanche in the well that can destroy the ESP. The rate is also limited by the maximum rate at the process facility. I chose to use this formula and the rate it gives, because it was the best assumption I had.

Some of the wells that are being evaluated might not get a list over the applicable pumps. This happens because the rate the program is calculating, the design rate, is either too high or too low. When the rate is too high, the Prosper model can't find any pumps that can deliver the rate that the program has given. When the rate is too low, the head that the pump must deliver can be negative, since the pressure in the reservoir is already delivering at a higher rate. Even though the program does not find any applicable pumps, the net present value will still be calculated, based on the design rate. To avoid this problem there should be a safety feature that checks if no pumps are applicable and does the ESP design calculation all over again, with either a higher or a lower design rate. This problem has not been fixed due to time limitation.

4.6   User friendliness

The program as it is now is not user friendly at all. In order to change parameters you must physically enter the C#-program and find the correct line where the parameter has been declared. In order to do this, it requires some pre-knowledge of coding, and the reason it is like this is the time-limitation. Before the user friendliness is dealt with, I think that all the problems mentioned above should be fixed.

The plan for how the program would appear and function was as follows. When the users open the program, they can decide which field and well they want to evaluate. They can choose whether or not to input their own parameters or if they would like to use default values. After the program was finished and they had looked at the results, they would have the possibility to do changes in the parameters, such as the wellhead pressure or the ESP removal cost, and run it again. With this feature they can find how the ESP will function best and how to get the highest net present value. All results would be shown on the screen and the users could easily find production graphs and check the data used.

The program should also be able to be run on all the wells in the system. Then the program could be started one day, and the next day it would be finished. The point with running it on all of the wells is that the most recent production data would be taken into consideration and the company would always have an updated list on which well they should take a closer look at for installation of ESP. The results from this operation should, in my opinion, be a list of all the wells which were evaluated and their corresponding net present value, sorted after the net present value. By running this operation once a month, it would also give the company a way to track the wells and more easily have determined which wells that should get an ESP installation.

4.7   Future work

In order to get this program to function for every well, there is still some work that needs to be done. For every well there are small differences that separate them from other wells, such as the casing data or the tubing data, to mention two things. When making a program run automatically, all these little differences needs to be accounted for in order to make it run smoothly.

First and foremost all the problems and weak assumptions in chapter 4.1 - 4.5 needs to be dealt with. The most urgent problem is to find a better water cut estimation, where the water cut values doesn't reaches one as fast as it does now. The next step would be to find a better way to separate the different production. The program should contain three different methods of calculating the net present value, depending on which type of well is being evaluated.

When all these problems and weak assumptions have been dealt with, the points mentioned in chapter 4.6 User Friendliness should be incorporated in the program making it easier to use for everyone who is not familiar with the art of coding to use the program.

5   Conclusion

The ESP Screening tool consist of approximately 1800 coded lines and has evaluated 10 wells for installation of ESP. The ESPs assumed lifetime is three years. ESP Due to a weak water cut estimation, all the net present values calculated by the ESP screening tool has been negative for all the wells evaluated. In order to evaluate the well, the ESP screening tool compares future production with and without an ESP installed in the well. The ESP screening tool then takes the difference in production, calculates the production value minus the costs of installing, running and removing an ESP and calculates a net present value. To find future fluid production and future water cut values the ESP screening tool estimates new values, based on previous production rates.

This ESP screening tool is currently a rough screening of the wells and the calculated net present value gives an indication whether or not to consider a well more thoroughly. In addition to giving a net present value for the well, the ESP screening tool also uses Prosper to simulate an ESP in the well and finds applicable pumps to use.

The ESP Screening tool is not completely finished, even though it is capable of evaluating wells and giving out results. There is still more work to be done in order to have a screening tool that can be used by professionals.

6 Referances

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Nomenclature

ESP – Electrical Submersible Pump

C# - Programming Language

Prosty – Production database

CSD – Casing string Design, tubing database

Prosper – Well simulation program

NPV – Net Present Value

WC – Water Cut

GOR – Gas-Oil Ratio

TTCESP – Through-Tubing Conveyed ESP

q_o – Estimated starting rate

q_{ESP} / q_{design} – ESP starting rate

D – Constant, from Arp's formula used in production estimation

c_0 / c_1 – Constants, used in water cut estimation

P_i – Installation cost of ESP on a platform

P_r – Running cost of ESP per year

P_{rem} – Removal cost of ESP

P_o – Oil Price Sm3/NOK

Sm3 – Standard cubic meter

NOK – Norwegian Kroner

k_d – Discount rate

SQL – Structured Query Language

OD – Outer Diameter

ID – Inner Diameter

MD – Measured Depth

TVD – True Vertical Depth

PI – Production Index

Pres – Reservoir Pressure

Pb – Bubblepoint Pressure

q,0 – fluid rate at time t

q,0i – Initial fluid rate

t – Time-parameter

prod_acc – Accumulated Production

Self_prod – variable, used to declare if a well is self producing

GLF – Gas-Liquid Fraction

IOR – Improved Oil Recovery

MSR – Maximum Sand-free Rate

Appendix A: Net present value calculation of well 2

Well 1 is assumed have a decline of ten percent per year, since the D-value from the production estimation is greater than zero. All the rates and results are given as fraction of the starting ESP production rate. Since the future production rates and water cut values is being calculated for each of the 1095 days, only the first 20 lines will be shown to give an indication of how the program is calculating these answers. The final calculation will be shown in the end.

Input	Value
Decline per year	0,9
Total Decline	0,729
q,i, start rate from production estimation	
Start production without ESP	0,668
Start production with ESP	1,00
D, constant from production estimation	
T1	0
T2	1094
Discount rate	10 %
Installation cost ESP	100 MNOK
Running cost ESP per year	1,5 MNOK
Removal cost ESP	25 MNOK
Oil price	4000 NOK
Accumulated production from Prosty	344,899
C0, constant from water cut estimation	5,7955E-05
C1, constant from water cut estimation	16,0656

Table 4: Input well 2

Day	Time factor	Prod	Acc. Prod	WC-prod	New prod	ESP-prod	Acc. ESP	WC-ESP	New ESP	diff
0	0,0009	0,6681	0,668	0,9807	0,01288	1,0000	1,000	0,9807	0,0193	0,0064
1	0,0018	0,6679	1,336	0,9807	0,01286	0,9997	2,000	0,9808	0,0192	0,0064
2	0,0027	0,6677	2,004	0,9808	0,01284	0,9994	2,999	0,9808	0,0192	0,0063
3	0,0037	0,6676	2,671	0,9808	0,01282	0,9991	3,998	0,9808	0,0191	0,0063
4	0,0046	0,6674	3,339	0,9808	0,01280	0,9988	4,997	0,9809	0,0191	0,0063
5	0,0055	0,6672	4,006	0,9808	0,01278	0,9986	5,996	0,9809	0,0190	0,0063
6	0,0064	0,6670	4,673	0,9809	0,01276	0,9983	6,994	0,9810	0,0190	0,0062
7	0,0073	0,6668	5,340	0,9809	0,01274	0,9980	7,992	0,9810	0,0190	0,0062
8	0,0082	0,6666	6,006	0,9809	0,01271	0,9977	8,990	0,9810	0,0189	0,0062
9	0,0091	0,6664	6,673	0,9810	0,01269	0,9974	9,987	0,9811	0,0189	0,0062
10	0,0101	0,6662	7,339	0,9810	0,01267	0,9971	10,984	0,9811	0,0188	0,0062
11	0,0110	0,6660	8,005	0,9810	0,01265	0,9968	11,981	0,9811	0,0188	0,0061
12	0,0119	0,6658	8,671	0,9810	0,01263	0,9965	12,977	0,9812	0,0188	0,0061
13	0,0128	0,6656	9,336	0,9811	0,01261	0,9963	13,974	0,9812	0,0187	0,0061
14	0,0137	0,6654	10,002	0,9811	0,01259	0,9960	14,970	0,9813	0,0187	0,0061
15	0,0146	0,6652	10,667	0,9811	0,01257	0,9957	15,965	0,9813	0,0186	0,0060
16	0,0155	0,6650	11,332	0,9811	0,01255	0,9954	16,961	0,9813	0,0186	0,0060
17	0,0165	0,6649	11,997	0,9811	0,01253	0,9951	17,956	0,9814	0,0185	0,0060
18	0,0174	0,6647	12,662	0,9812	0,01251	0,9948	18,951	0,9814	0,0185	0,0060
19	0,0183	0,6645	13,326	0,9812	0,01249	0,9945	19,945	0,9814	0,0185	0,0060

Table 5: Calculation data

	Year 1	Year 2	Year 3
Diff. Prod	1,4037295	0,6106724	0,3377115
Prod. Value	5614,9181	2442,6897	1350,8458
Net Present Value	-60383,90		

Table 6: Net Present Value Calculation for well 2